State and Federal Applications for Renewal of the Trans Alaska Pipeline System

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Appendix 1
TAPS Design and Construction

The original construction cost of TAPS, including the VMT and the Haul Road (now the Dalton Highway), was approximately $8 billion in 1977 dollars (APSC, 1999a; Patton, 1977). The original environmental impact statement for TAPS (BLM, 1972) filled six volumes, distilled the results of 1,300 studies, required 175 person-years to complete, and cost between $9 million and $12.7 million in 1972 dollars (Mead, 1978; Coates, 1993; Cole, 1997).

The design and construction of this pipeline presented unprecedented technical, logistical, political, and regulatory challenges. The technical challenges led to innovative solutions that have been widely applied in arctic engineering and pipeline design and operation. Below is a brief sample of TAPS pioneering accomplishments.

- **Arctic technology:** New arctic and subarctic techniques were used for the design and construction of TAPS.
- **Vertical support members** (VSMs): Alyeska developed new criteria for installation of support piles in permafrost and designed new boring equipment to install the VSMs.
- **VSM heat exchangers:** VSM heat exchangers, or *thermosiphons*, originally developed for the space industry, were adapted to maintain permafrost conditions along TAPS.
- **Seismic design:** Alyeska's adoption of seismic criteria for pipeline design was the first of its kind in the industry.
- **Wildlife crossings:** Large sections of buried pipe were engineered to accommodate the movement of large mammals.
- **Leak detection system:** The *transient volume balance* system is the first of its kind in the industry and increased leak-detection sensitivity fourfold.
- **Smart pigs:** Alyeska developed and uses state-of-the-art, high-resolution "smart pigs" to detect corrosion, pipe curvature, and deformation.
- **Drag-reducing agent (DRA):** Conoco Specialty Products developed DRA, and Alyeska pioneered its use on a large scale. DRA is now used in pipelines around the world.
- **Mobile wildlife stabilization and cleaning units:** Alyeska redesigned existing technology to allow mobile operations to help wildlife affected by a spill.
- **Portable dams:** Alyeska designed and built a portable dam for spill response on small streams.
- **High-volume skimmers:** The Spill Escort/Response Vessel System uses this technology, designed by an Alyeska contractor for Prince William Sound.
- **Measurement of telluric currents:** Telluric currents are electrical currents associated with the earth's magnetic fields. In response to a Department of Transportation concern that telluric currents could interfere with accurate cathodic protection monitoring, Alyeska developed a method to measure and compensate for these currents. The pipeline's considerable length, the fact that much of it is above ground, and its latitude mean these currents are larger than those present on other pipelines.
- **Corrosion coupons:** Alyeska, in partnership with the JPO and the federal Office of Pipeline Safety, developed and enhanced corrosion coupons for use with buried pipelines to monitor the effectiveness of cathodic protection. Corrosion coupons, which are small pieces of steel with the same metallurgical properties as the pipeline, are buried next to the pipe and connected to it by wires. Corrosion on the coupons is representative of pipe corrosion.

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Photo 5. *VSMs elevate the pipeline in areas of thaw-unstable permafrost.*

Appendix 2
Physical Life

A2.1 Pipeline Longevity/ Performance Studies

In addressing TAPS longevity, it is useful to compare the TAPS operating period with that of other pipelines. Some pipelines have been in good operating condition for more than 50 years (Muhlbauer, 1996).

A study of Cook Inlet, Alaska, oil pipeline performance performed by ADEC noted (Visser et al., 1993):

> The fact that the pipelines have reached their original design life does not imply that the lines have become inadequate or unsafe. The integrity of an older pipeline is a function of how well the line has been maintained, the type of throughput, and how the current operating conditions compare with the original design conditions. With proper maintenance the remaining life of a pipeline can be several multiples of the original design life.

Several studies have examined the effect of aging on pipelines. In one recent study, a European pipeline consortium collected data over a 25-year period on the performance of cross-country oil pipelines in Western Europe (Lyons, 1998). The data were analyzed to record the pipeline system development over time, quantify environmental performances, and reveal trends in causes of spills. The following summarizes the findings of the study:

- In 1971, 70 percent of the pipelines inventoried were 10 years old or less, but by 1995 only 8 percent were 10 years old or less and 30 percent were over 35 years old.
- Pipeline spills averaged fewer than 14 per year and most were very small. Less than 5 percent of the spills were responsible for 50 percent of the gross volume spilled.
- Over the 25 years, the frequency of spills improved from 1.2 spills per 1,000 kilometers (620 miles) of pipeline to 0.4 spills per 1,000 kilometers.
- The two most important causes of spills are third-party accidents and mechanical failure, with corrosion in third place, and operational and natural hazards making minor contributions.

The study concluded that there is no evidence that the aging of a pipeline system increases risk. The development and implementation of new techniques, such as internal inspection using smart pigs, hold out the prospect that pipelines can continue reliable operations for the foreseeable future.

In assessing TAPS longevity versus performance, it is useful to review oil spill statistics over time. If aging of TAPS increased risk, an upward trend in oil spills would be noted. Such an analysis was done for the draft *Environmental Report for Trans-Alaska Pipeline System Right-of-Way Renewal* (TAPS Owners, 2001) being prepared in conjunction with this report. Figure 6 presents volumetric spill rates by year for the pipeline. There is substantial variability, but also evidence of a downward trend in volumetric spill rates in later years. (All large pipeline spills occurred during the first five years of operation of TAPS. None has occurred since 1987.) A linear regression line (the dashed line in Figure 6) has a negative slope, indicating decreasing volumes spilled. Nonetheless, the predictive power of the linear trend model is not high, indicating that year-to-year

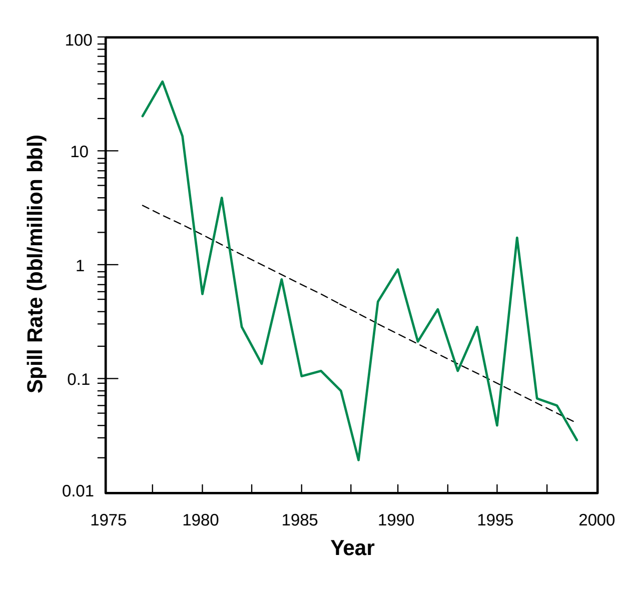

Figure 6. *Volumetric spill rate for the pipeline (1977-1999).*

variability is large relative to any time trend. For this reason, it is conservatively assumed that the volumetric spill rate is constant over time. Consequently, oil spill statistics do not indicate a pipeline nearing the end of its useful life.

A2.2 Age-Related Effects on Pipelines

Age itself has no metallurgical effect on the microcrystalline structure of steel that would cause the strength and ductility of the pipe to degrade over time. However, several ways that the age of a pipeline can influence the potential for failures are corrosion, fatigue, and manufacturing and construction methods (Muhlbauer, 1996; Crocket and Maguire, 1999). An indirect effect of age is the increased time when a pipeline is exposed to the threat of "outside-force damage" (damage caused by accidental impact from an external force such as a vehicle or heavy equipment).

The following discussion highlights these effects on pipelines in general. Following this discussion is a section describing techniques and programs used specifically on TAPS to mitigate the threat of these age-related effects.

- **Corrosion** is related to the environmental conditions surrounding the pipe. It is reasonable to assume that with the passage of time, the opportunity for undetected (and hence, uncontrolled) corrosion and/or fatigue effects increases. Pipe-coating systems are susceptible to deterioration over time from mechanical abrasion and chemical reactions from absorbing gases and liquids in the surrounding environment. Pipeline operators use corrosion-control programs to counter the threat from corrosion
- **Fatigue stresses** that result in cracks are a potential effect of age in metal pipelines. Fatigue cracks, if unchecked over time, can lead to pipe failure. Pressure fluctuations during pipeline operation over long periods can lead to fatigue. Common practices used to detect fatigue are fatigue monitoring, hydrostatic testing, and in-line inspection with crack detection tools.
- **Manufacturing and construction methods** can affect physical life. Poor field welds, incomplete fusion of longitudinal pipe seams, and defects in the steel manufacturing process could contribute to pipe failure over time. Although most defects of these types are detected before initial pipeline operation, some defects could manifest themselves over time as pressure cycles, fatigue stresses, and external impacts affect the pipe. Radiographic examinations of welds, construction and manufacturing inspections, hydrostatic testing, and in-line inspections are methods by which this threat to pipeline integrity is detected.
- **Outside-force damage** is an indirect age-related effect on physical life simply by the increased time of exposure to potential incidents. Damage caused by outside forces is usually localized and is minimized by information dissemination (e.g., posted notices, public awareness campaigns), surveillance, and monitoring.

A2.3 Mitigating the Effects of Age on TAPS

Potential effects of age discussed above are countered on TAPS through surveillance and maintenance programs to identify flaws in coatings, to provide adequate cathodic protection, to monitor pipe condition through in-line inspection, and to perform hydrostatic testing. If the potential age-related effects are properly controlled, the physical life of the steel pipe is considered essentially unlimited. On TAPS, potential age-related threats are mitigated as described below.

A2.3.1 Corrosion

Mainline pipeline corrosion is controlled using Alyeska's *Corrosion Control Management Plan* (CCMP), which is more fully discussed in Section A3.3 as an example of a comprehensive integrity monitoring program.

Monitoring of corrosion protection is accomplished in several ways. Cathodic protection monitoring of mainline pipeline takes place annually. Data are gathered from test stations, buried corrosion coupons, cased road crossings, and the fuel gas pipeline. Cathodic protection data also are gathered at buried propane tanks, pump stations, and the VMT. Rectifiers are checked six times a year.

Inhibitors are used to control corrosion in isolated and low-flow or seldom-flow piping in pump stations and in road-crossing casings. Internal coupons, which verify the effectiveness of the inhibitors, are removed and analyzed twice yearly. In-line inspection tools ("pigs"; see Photo 6) are used to monitor corrosion and curvature on the mainline pipeline. Data are collected, stored, evaluated, and trended.

A2.3.2 Fatigue

Cracks from fatigue stresses can affect the physical life of metal pipelines. On TAPS, two potential fatigue-stress scenarios exist: structural resonance of the piping and pipeline pressure-cycling.

Structural resonance of piping occurs in the piping manifolds of mainline pumps when the pump impeller


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Photo 6. *Smart pig.*

spins at a rate that can excite the piping or its appurtenances at their natural structural frequency, resulting in high vibration and stress levels. Structural resonance manifests itself only in piping and appurtenances adjacent to the mainline pumps. Operators routinely check for fatigue damage to piping near the mainline pumps and implement corrective measures as required to maintain system reliability.

Pressure-cycling is a concern only in areas on the mainline pipe where dents, sleeves, or similar anomalies can result in localized pipe-wall bending stresses as the pipe goes through changes of pressure. The degree of potential fatigue damage depends on the number of cycles and the stress magnitude for each cycle. For dents, sleeves, and other pipeline anomalies, the potential fatigue stresses can be high during shutdowns and restarts, but the number of cycles is low. In areas where the cycles may be high, such as at the base of slackline areas, the pressure deviations and resultant stresses are low. These slackline areas, such as Thompson Pass, have been studied, and either fatigue life has been determined to be unlimited or corrective actions have been implemented. (Baskurt et al., 1998; Hart et al, 1998; Norton et al., 1998; Stevick et al, 1998; Tart and Hughes, 1998; Tonkins et al., 1998)

A2.3.3 Manufacturing and Construction Methods

Manufacturing defects or poor construction methods could have a deleterious effect on the longevity of a pipeline. However, TAPS was built under the most stringent criteria available and was closely inspected, tested, and monitored. The following examples of pipe materials, welding, and valves indicate the level of mitigating measures employed.

Mainline Pipe. TAPS pipe is carbon steel (API 5LX and 5LS) with five different pressure capabilities. There are two wall thickness (0.462-inch and 0.562-inch) and three specified minimum yield strengths (60,000 psi; 65,000 psi; and 70,000 psi).

The design basis criteria for allowable curvature were based on pre-construction mainline pipe testing at the University of California at Berkeley (Bouwkamp and Stephen, 1974). In order to study the potential behavior of the pipeline prior to construction, test specimens were subjected to a number of different load conditions. The basic parameters in these studies were the internal pressure and the temperature differential between tie-in or installation temperature and operating temperature. To evaluate these phenomena under increasing lateral loads, a total of seven specimens under different pressure and simulated temperature conditions were investigated. These tests continued until the pipe wall buckled. For five specimens, tests continued until the pipe wall ruptured. Furthermore, one test specimen was used to study the effect of a pressure drop on pipe-wall stability.

Recently, several engineering studies and tests (SSD, 1997; SWRI, 1999) have led Alyeska to develop tools to evaluate the below-ground pipe at specific locations on the basis of the demand on the pipe and the pipe's particular capacity to resist bending. These studies and tools allow Alyeska to confirm that, in light of current technical knowledge, TAPS pipe continues to retain original throughput performance capabilities.

Welding. Welding on the pipeline, whether during construction or repair, must:

- Be performed by qualified welders in accordance with approved procedures;
- Be protected from weather conditions such as precipitation;
- Be performed in a manner to prevent, repair, or remove defects; and
- Undergo nondestructive testing.

The requirements for welding are located in Alyeska's *Corporate Welding Manual* (APSC, 1997) and *Trans Alaska Pipeline Maintenance and Repair Manual* (APSC, 1999b). These documents include instructions for complying with Department of Transportation requirements, in addition to the more stringent requirements for welding imposed by Alyeska's quality and safety programs.

All mainline pipe was hydrotested and all welds inspected by radiography before TAPS was commissioned. In the event that pipeline repairs require relocation or replacement, all replacement components undergo hydrostatic testing, and all mainline welds are inspected to ensure the integrity of the relocated or replacement pipe. Alyeska does not use any replacement pipe or component that has not been hydrostatically tested in conformance with Department of Transportation standards or that fails to meet hydrostatic testing standards.

Valves. Alyeska specifications for the design of mainline valves require conformance to American Petroleum Institute standard API 6D, as well as several other requirements. Department of Transportation regulations under 49 CFR 195 also require that new valves meet the test requirements of API 6D, which covers valves of 2-inch nominal pipe diameter and larger.

The Department of Transportation regulations also require pipeline operators to maintain those valves "required for safe operation" in good working order. Alyeska maintains its valves in good working order and demonstrates the functionality of the valves through partial closure of the valves twice a year. In addition to the regulatory requirements, Alyeska implemented the TAPS Valve Program in 1997 to validate the condition of these valves and to perform testing to determine if the valves performed in accordance with criteria developed by Alyeska. Valves that do not met performance criteria are repaired or replaced. (Aus et al., 2000; Jackson and White, 2000; Pomeroy and Norton, 2000; Weber and Malvick, 2000)

A2.3.4 Outside-Force Damage

Approximately half of the 800-mile pipeline is above ground and, therefore, potentially subject to damage caused by accidental impact from an external force such as a vehicle or heavy equipment. Access to most of the right-of-way is limited by the federal (Bureau of Land Management) and state (Alaska Department of Natural Resources) landowners. In addition, Alyeska limits access to the pipeline through signs and with locked gates on access roads to the right-of-way. For locations where access roads pass under the pipeline, "headache" bars have been installed to ensure that vehicles have enough clearance under the pipe.

For below-ground pipe, all excavation within the right-of-way must be authorized by Alyeska and conducted in accordance with Section 9 of the *Trans-Alaska Pipeline Maintenance and Repair Manual* (APSC, 1999b). This manual provides stringent requirements to safeguard below-ground pipe. Warning signs along the pipeline contain a 24-hour telephone number (907-835-4709) to contact the Controllers at the Operations Control Center (OCC). Callers with excavation requests are connected with the appropriate personnel to coordinate excavation requirements. In addition, Alyeska conducts an educational program to help the public, government organizations, and people engaged in excavation-related activities to recognize a crude-oil pipeline emergency and to report it to Alyeska and/or other emergency response organizations.

Alyeska's pigging program monitors the pipeline for external damage using ultrasonic technology to detect pipe-wall thinning from gouges and scrapes. Other curvature pigs detect dents and ovalities.

Leak detection systems monitor for leak loss from any source, including outside-force damage.

Appendix 3
Maintenance and Surveillance Programs

The key programs that support TAPS' continuing health and useful life include uniquely designed maintenance and repair programs, and comprehensive integrity monitoring and surveillance programs. This appendix highlights the important elements of each program. The discussion focuses on elements that keep TAPS functioning according to its original design criteria and capabilities. The scale and scope of the maintenance and integrity monitoring efforts on TAPS can best be seen by examining an example of one of the component programs in detail. Accordingly, an extended discussion of the corrosion control program is provided in Section A3.3.

A3.1 Maintenance and Repair Programs

The TAPS maintenance program is designed to preserve the integrity of TAPS facilities, systems, and equipment. Program activities include determining appropriate maintenance strategies; identifying and documenting maintenance work; performing preventive, predictive, and corrective maintenance; recording maintenance trends and history; and documenting completed work. Repair programs incorporate major maintenance, refurbishment, and replacement of facilities and components.

> ***Examples of Pipeline Maintenance***
>
> - Maintaining valves, motors, pumps, flow meters, instrumentation, electrical systems, supervisory control, and communications.
> - Calibrating all instrumentation to comply with company standards, manufacturers' recommendations, and applicable state and federal regulations.
> - Maintaining buildings and facilities, which support operations and maintenance.
> - Maintaining pipeline structural integrity.
> - Maintaining corrosion protection systems.

A3.1.1 Maintenance Strategy

The TAPS maintenance strategy focuses on principles of reliability-based maintenance, which emphasizes understanding how equipment fails and identifying potential failures before they have a negative impact. This approach anticipates problems and entails planning and scheduling work, condition monitoring, and the use of predictive maintenance tools, maintenance-performance measurements, and equipment-reliability analyses.

As is the case with all of its integrity management efforts, Alyeska strives to meet a goal of continuous improvement in its maintenance programs. To assess the state of these programs, Alyeska recently completed an assessment of its maintenance management systems and processes, seeking to optimize both reliability and maintenance performance and practices. Implementation of the recommended improvements is underway.

A3.1.2 Maintenance Process

The maintenance process is an ongoing cycle and is designed to build on and disseminate learning from past experience. The cycle works as follows:

1. Maintenance processes and procedures are first developed for consistency throughout the organization and prioritized according to safety, environmental, regulatory, operational, and economic considerations, in that order.
2. The TAPS computerized work-management system, called PassPort, creates maintenance work orders and then captures feedback from technicians who have completed maintenance work.
3. The maintenance engineering staff evaluates the information — looking for breakdown and other unusual trends — and then designs responses to mitigate future failures.
4. Periodic reviews, audits, and surveillance ensure uniformity and compliance with the processes and procedures. When needed, procedures are updated, and the cycle begins again.

A3.2 Monitoring and Surveillance Programs

TAPS monitoring and surveillance programs buttress the maintenance and repair programs and are designed to identify, at the earliest possible time, threats to the integrity of TAPS so that effective intervention steps can be taken. Pipeline integrity is based on a comprehensive program of system monitoring and surveillance closely integrated with maintenance and repair programs.

Monitoring activities measure and collect discrete data points, such as pipe wall thickness or temperature readings. Surveillance activities are observations, typically visual, of changes to the system, such as blocked culverts or workpad erosion. Monitoring and surveillance programs are comprehensive and varied. Some of the more important efforts include the following:

- The above-ground pipe-support system is monitored for trends indicating instability using slope indicators, temperature measurements at depth, aerial infrared video checks of pipe-support performance in permafrost, and overload checks at critical supports. The below-ground pipe is monitored for wall thinning, curvature caused by settlement, and deformations and dents using a suite of instrumented inspection tools (pigs).
- Pipeline surges and pressures are monitored and controlled through automatic systems. The pressure-control system continuously detects, alarms, and alerts technicians controlling the pipeline in the event pressures anywhere in the pipeline approach maximum allowable operating pressure limits. This system would also safely shut down the pipeline if the controllers were not to respond promptly enough to the alarms. In addition, multiple detection methods are employed to continuously monitor the pipeline for leaks.
- Pipeline valves also are monitored. Soil-gas probes are installed at all below-ground main pipeline valves to detect the release of oil from small weeps or leaks which would otherwise be too small to be visible or to be detected by other leak detection methods.
- Regular surveillance along the entire length of the pipeline is performed from the ground or air at intervals not exceeding two weeks. Specialized surveillance inspections are conducted regularly at river-crossing structures and for glacier movement, slope stability, and fish blockage. Annual line walks, patrols by security personnel, pipeline system maintenance, and field activities provide additional surveillance.
- Pipeline bridges are inspected annually, and a detailed professional engineering evaluation of bridges is performed every five years. Security surveillance is provided by remote video and motion sensors for bridges over the major rivers — the Yukon, Tanana, Gulkana, and Tazlina.

A3.3 Corrosion Monitoring and Control

The TAPS comprehensive corrosion control program is a key factor in maintaining the safety, integrity, and serviceability of the pipeline. This is true because if corrosion is properly controlled, the physical life of the steel pipe is considered essentially unlimited. This program also illustrates the care and attention built into all efforts to maintain the system to meet all design and operating criteria, as well as regulatory requirements, over the long term. Accordingly, a more detailed discussion of this critical program is warranted.

The potential effects of corrosion are countered through a number of programs which meet and exceed industry and regulatory agency standards for corrosion detection and control. These programs identify flaws in pipe coatings, provide cathodic protection of the pipe, and monitor pipe condition through in-line inspection tools. Alyeska pioneered many of these tools and techniques (Appendix 1).

The TAPS *Corrosion Control Management Plan* (CCMP; APSC, 1999c) is designed to detect mainline pipe corrosion and intervene long before pipeline integrity is compromised. The plan focuses on the mainline pipe. Other separate and comparably rigorous programs address tanks, pump stations, and the Valdez Marine Terminal.

The CCMP includes:

- A computerized corrosion data management system.
- Cathodic protection monitoring,
- Enhanced (primarily impressed-current) cathodic protection at selected sites,
- Collection and analysis of corrosion pig data, and
- A monitoring methodology that combines all pipeline integrity data.

These five elements of the CCMP overlap and support a broad, systematic approach to corrosion control.

A3.3.1 Corrosion Data Management System

The corrosion data management system contains millions of data points — cathodic protection readings, geophysical data, smart pig data, and ultrasonic testing data. The system enables engineers to track pipe corrosion changes over time and thus help them make maintenance decisions.

A3.3.2 Cathodic Protection Program: Monitoring and Enhancement

External pipeline corrosion is controlled through pipe coatings and cathodic protection. Pipe coatings prevent water and soil from making direct contact with the pipe steel, thus eliminating the electrolytic path necessary for corrosion to occur. When the coating is damaged or otherwise compromised, the pipeline can corrode (Lara and Klechka, 1989). Cathodic protection reduces or eliminates corrosion by making the pipe a cathode in an electrochemical circuit. In such a circuit, the cathode does not corrode. The anode is created by means of an impressed direct current or by connection to a sacrificial metal, such as zinc.

Alyeska's cathodic protection program consists of two systems: galvanic and impressed-current. The galvanic system was part of the original corrosion protection design. Twin zinc-ribbon anodes were placed in the mainline pipeline ditch and connected to the pipe during construction of the 376 miles of buried pipeline. These zinc connections corrode sacrificially and protect the more resistant steel pipe. Monitoring of the system indicates where additional protection is required over time. The impressed-current system uses outside electrical power to provide current to some sections of the pipeline sufficient to overcome natural electrolysis where soil moisture is present.

Performance of the cathodic protection systems is regularly monitored by collecting and analyzing data from various test sources and surveys which measure protection levels (Stears et al., 1997; Stears et al., 1998). Impressed-current systems have been placed on approximately 350 miles of pipeline.

Alyeska, in partnership with the Joint Pipeline Office and the federal Office of Pipeline Safety, developed and enhanced corrosion coupons for use with buried pipelines to monitor the effectiveness of cathodic protection. Corrosion coupons are small pieces of steel with the same metallurgical properties as the pipeline. They are buried next to the pipeline and connected to it by wires. Corrosion on the coupons is representative of pipeline corrosion.

Alyeska installed 650 coupons on TAPS between 1994 and 2000. These coupons were initially placed at roughly a one-mile spacing, and additional coupons were tested using more stringent criteria. Cathodic protection coupons are monitored annually, and the information collected, along with other data, is used to assess the status of the pipeline cathodic protection system and the overall performance of the corrosion control system. Remedial action is taken if cathodic protection is not adequate by National Association of Corrosion Engineers' criteria.

A3.3.3 Pipeline Integrity Monitoring and Evaluation

Integrity monitoring consists of in-line corrosion monitoring using "smart pigs" — instrumented devices which travel through the pipeline and electronically record information about the internal and external condition of the pipeline. Maintenance and repair efforts are based on the analysis of this information.

In addition to data on corrosion, smart pigs provide data on curvature (pipe settlement) and deformation (dents and buckles). For the mainline pipeline, a three-year cycle is currently used — that is, the corrosion pig is run one year, the curvature pig the next year, and the deformation pig the following year.

Corrosion pigs detect and record the size of corroded pits, determine whether the corrosion is external or internal, and measure wall loss from corrosion or mechanical damage. Corrosion pig data detect many types and locations of corrosion — at welds, under insulation, and at transitions — as well as general corrosion of TAPS mainline pipe. By detecting changes from one pig run to the next, the corrosion pigs help point out areas where active corrosion is occurring and allow Alyeska to target those areas for supplemental cathodic protection or repair (Johnson and Bieri, 1998).

A3.3.4 Integrated Pipeline Integrity Monitoring

In order to continually improve pipeline safety and integrity, evolution of the program will expand and coordinate the current corrosion monitoring effort to address all potential pipeline integrity threats. An important feature of the developing Integrity Management Plan is the integration of information and methods. This approach recognizes that the best way to assure integrity is to apply an overlapping and diverse mix of methods — such as the combination of deformation, curvature, and corrosion pig data — into a uniform analytical process.

Appendix 4
TAPS Major Components

TAPS is a complex system that moves a million barrels of oil per day across 800 miles (Figure 7), three major mountain ranges, hundreds of rivers, and three major seismic faults. This requires effective coordination and reliable equipment. Many diverse functions must be performed to get crude oil through the pipeline safely, without harming the environment, and while remaining in compliance with applicable laws and regulations.

Key components of TAPS, as well as less critical ones, are well maintained and are upgraded or replaced as necessary to ensure the integrity of TAPS for a virtually unlimited time. Table 2 gives a brief overview of major TAPS components, related longevity issues, and prevention and mitigation measures.

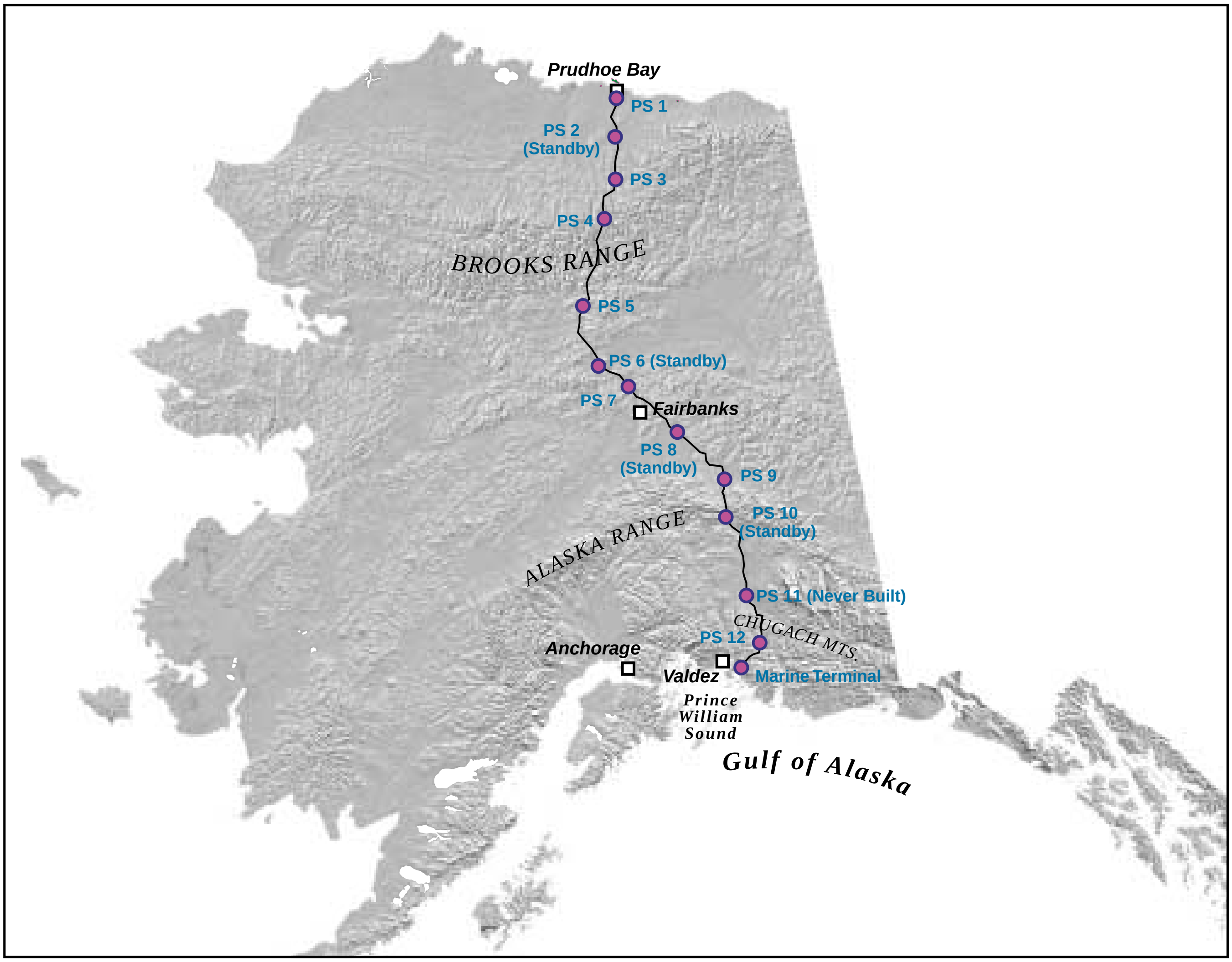

Figure 7. *The Trans Alaska Pipeline System.*

Table 2. *Prevention or mitigation of TAPS longevity issues.*

Component	Issue	Prevention/Mitigation Method
Mainline Pipe	Overpressure	Pressure relief system.
	Corrosion	Design: pipe selection, coating, etc. Maintenance of cathodic protection. Integrity monitoring. Corrosion data collection and management.
	Fatigue	Case-by-case evaluation and repair as necessary.
	Permafrost	Above-ground pipe. Heat pipes on VSMs. Refrigerated burial.
	Dents	Monitoring. Limited access to pipeline by vehicles/equipment. Case-by-case evaluation and repair as necessary.
Mainline Valves	Leakage/failure	Monitoring and maintenance, repair, and replacement. Performance standards more stringent than regulatory requirements.
	Communication failure for remote gate valves	Redundant communication systems. Optional manual operation. Operating policy to shut down pipeline in case of communication failure.
Crude Tanks	Tank corrosion	Secondary containment. Corrosion protection. Monitoring and maintenance.
	Piping corrosion	Minimal below-ground pipe. Monitoring and maintenance.
Pump Stations	Fire	Fire detection and suppression systems.
	Mechanical/electrical failures	Monitoring and maintenance. Case-by-case evaluation and repair.
	Earthquake	Earthquake monitoring system.
Valdez Marine Terminal	Mechanical/electrical failures	Monitoring and maintenance. Case-by-case evaluation and repair.
	Fire	Fire detection and suppression systems.
	Earthquake	Earthquake monitoring system.
	Ballast water tank corrosion	Elevated tanks (in progress). Monitoring and maintenance.
Ballast Water Treatment Facility	Piping corrosion	Monitoring and maintenance. Improved piping materials.
	Piping corrosion	Monitoring and maintenance. Improved piping materials.
Vapor Control	Detonation arrester reliability	New maintenance practices. Design improvements.
	Corrosion	Monitoring and maintenance.
Fuel Gas Line	Depth of cover	Monitoring and maintenance. Preventive maintenance/overfill.

Photo 7. *Transition between above- and below-ground pipe.*

A4.1 Mainline Pipe

The mainline pipe was installed between 1975 and 1977 and was commissioned in June 1977. Its design took into consideration local ground contours and pipeline pressure drop for moving fluids.

To accommodate arctic and subarctic conditions, the pipeline was constructed in three modes: conventional burial, above ground, and special burial. The above-ground and special-burial modes were designed to maintain the underlying permafrost, thus providing a stable foundation for the pipe. Permafrost soils, which may lose substantial strength on thawing, are prevalent on the northern three-fourths of the pipeline route.

In the above-ground mode, the pipe is insulated to protect against oil solidification and is elevated on a crossbeam attached to VSMs embedded in the permafrost. In the special-burial mode, the ground supporting the pipe is refrigerated.

A4.2 Pump Stations

Six pump stations are now operating along TAPS. The original design called for 12 to be situated at approximately 80- to 100-mile intervals for the purpose of boosting crude-oil pressure and providing relief tankage. However, Pump Station 5 is a relief station only and does not have pumps, and Pump Station 11 was never built. Because of decreased pipeline throughput, Pump Stations 8 and 10 were isolated from the pipeline in 1996, and Pump Stations 2 and 6 were isolated in 1997. These facilities are maintained such that they can be recommissioned within 180 days.

A typical pump station has a valve at either end to isolate it from the pipeline. A pump station includes a crude-oil breakout tank, large pumps to move the oil to the next pump station, oil spill response equipment, administrative offices, and living quarters for about 50 people. Several large valves control the route of crude oil within the station (i.e., whether it goes to the mainline pumps or bypasses them).

The pump stations are typically in remote locations with no other nearby facilities and are self-sufficient. Crews generally work for two weeks and then are gone two weeks. Alternate crews are flown in from Anchorage or Fairbanks. Typical manpower at a station consists of several maintenance and operation technicians and coordinators, a fire and safety representative, an engineer, security personnel, facility supervision, and an administrative assistant. Other people such as field environmental generalists, training generalists, and human resources personnel support and rove among several pump stations.

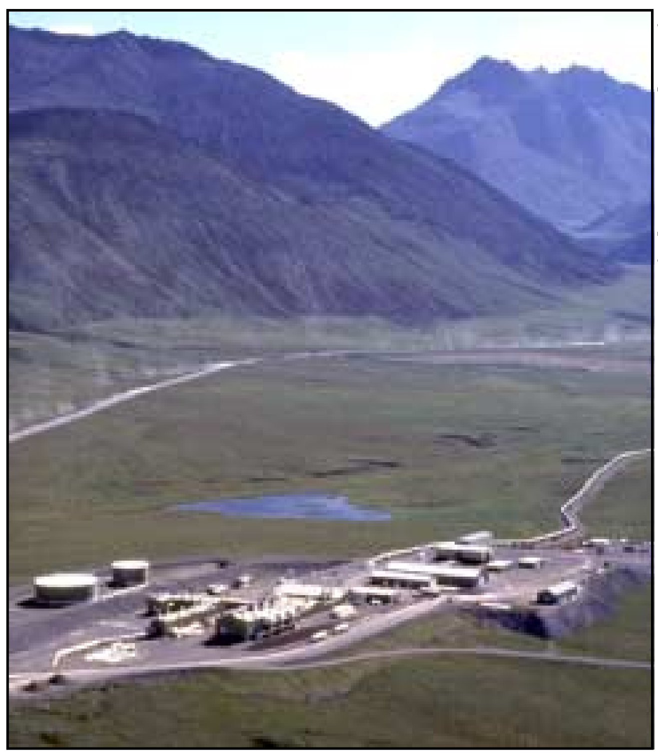

Photo 8. *Pump Station 4 in the Brooks Range.*

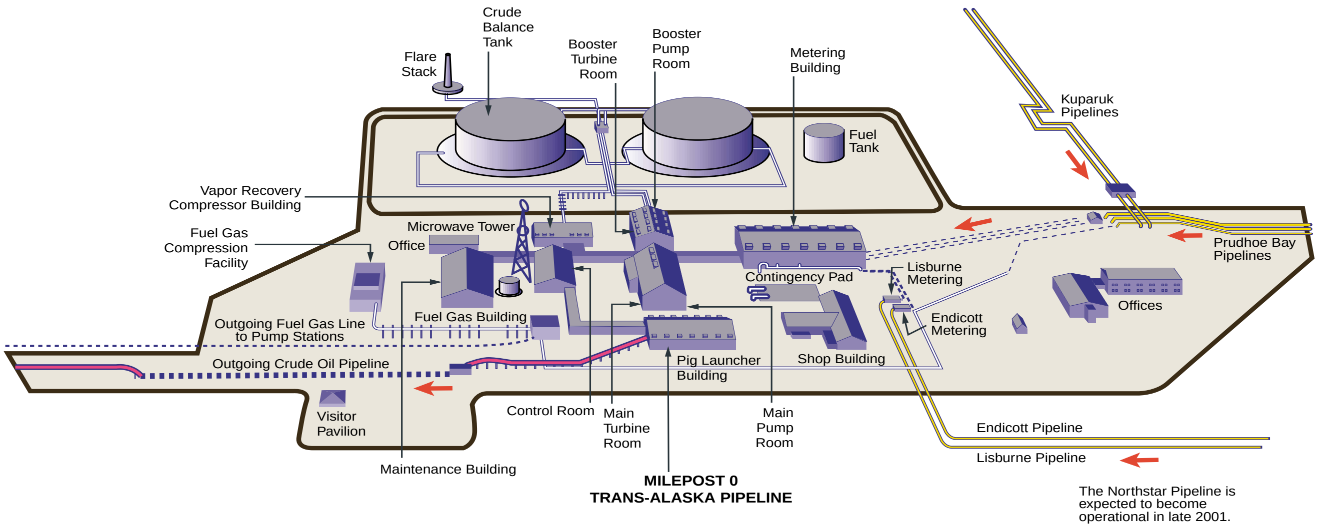

Figure 8. *Pump Station 1.*

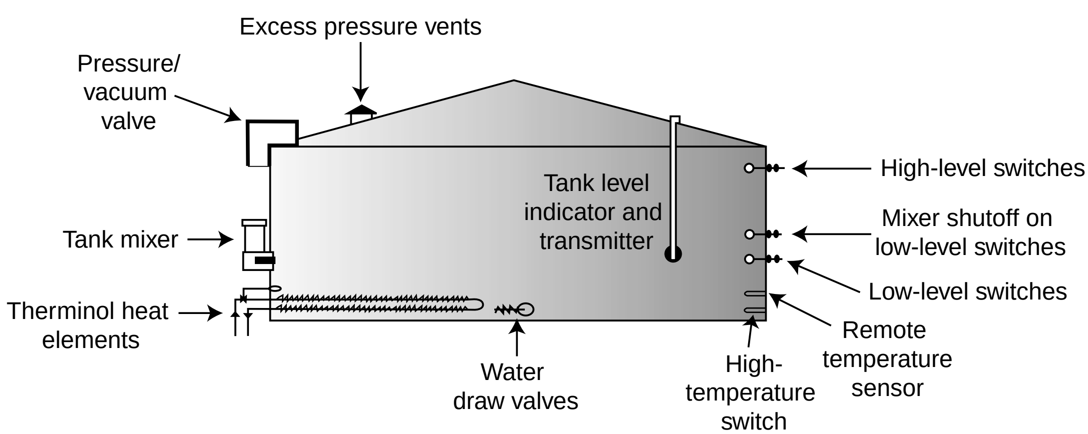

Figure 9. *Typical pump-station crude relief tank.*

Alyeska Pipeline Service Company

Photo 9. VMT East Tank Farm.

Alyeska Pipeline Service Company

Photo 10. TAPS check valve.

A4.3 Crude Oil Tanks

Thirty large crude oil tanks support the pipeline system. Eighteen of these are at the VMT, with the remainder spread among pump stations.

Pump Station 1 (Figure 8) uses two balancing tanks to control the flow to the booster pumps and into TAPS. Crude breakout tanks at Pump Stations 2 through 12 are part of the mainline relief system and are used to temporarily contain oil that is discharged from the mainline pressure-relief valves. Figure 9 shows the configuration of a typical pump-station crude relief tank.

At the VMT, Tanks 1 and 3 are dual-purpose relief and storage tanks. Tanks 2, and 4 through 18 are storage tanks to retain pipeline crude oil until it can be loaded on tankers. Oil flows by gravity from these tanks onto waiting tankers to be shipped out of state for processing. Photo 9 shows the East Tank Farm at the VMT.

A4.4 Pipeline Valves

The primary function of pipeline valves on TAPS is to minimize the amount of oil that would spill during a pipeline leak. TAPS valves also isolate pipeline segments for maintenance and to control pipeline overpressure.

TAPS has four types of pipeline valves: remotely operated gate valves (RGVs) at 63 locations, check valves (CKVs) at 81 locations, manual gate valves (MGVs) at 9 locations, and battery limit valves at 24 locations (Figure 10). All are 48-inch valves located either above ground or below ground in the mainline pipe.

- RGVs are located where rapid closure is required under emergency conditions — for example, at major river crossings or other environmentally sensitive areas. They are capable of stopping flow from either direction and are necessary to limit drainage in the event of a pipeline leak or break. (One ball valve, at Pump Station 11, performs the same function as the RGVs and is included in the count of 63 RGVs for purposes of this report.)
- CKVs limit drainage in the event of a pipeline leak or break on uphill slopes. They close automatically on flow reversal.
- MGVs are placed adjacent to check valves when necessary to provide more positive isolation and maintenance activities.
- A battery limit valve is placed on either side of each pump station and can be closed to isolate an active pump station from the pipeline. This prevents oil

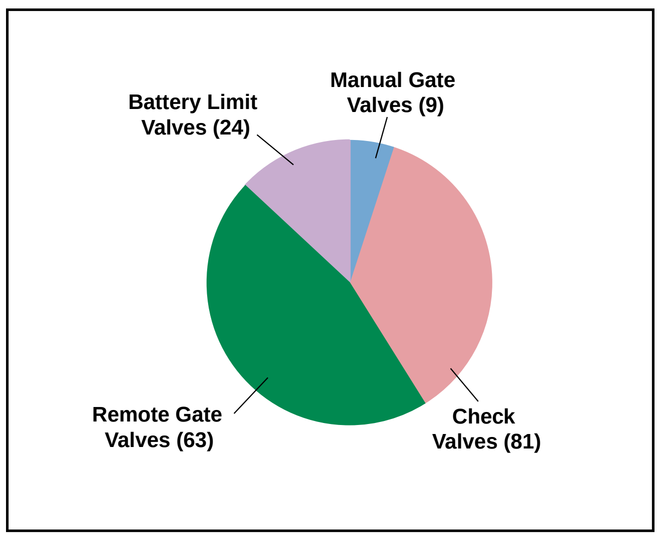

Figure 10. TAPS pipeline valves.

from entering the pump station in the event of a fire or other emergency at the station.

Alyeska's innovative valve-maintenance program ensures that the valves are sound.

A4.5 Fuel Gas Pipeline

A separate pipeline runs from Pump Station 1 to Pump Station 4 to provide natural gas for fuel to Pump Stations 1, 3, and 4 (Pump Station 2 has been placed on standby). The gas is the primary fuel for these stations, with diesel as backup.

Natural gas is produced with the crude oil pumped from the ground on the North Slope. Processing facilities separate the gas, and Alyeska purchases a portion to use as fuel.

The fuel gas pipeline is maintained and operated in accordance with federal regulations for cross-country gas pipelines. It is pigged regularly and is the focus of an aggressive corrosion-monitoring program, much like the crude oil pipeline.

Pump Station 1 supports various gas treatment and handling facilities. Chief among these is a fuel gas compressor module that compresses and cools the gas routed to Pump Stations 3 and 4.

A4.6 Relief Systems

Pressure-relief systems keep pressure in the pipe from exceeding the pipe's strength. In the pipeline, surge waves can be generated when pipeline flow stops quickly if a valve closes rapidly or crude oil pumps are stopped.

Pressure relief is provided at each pump station by suction- and discharge-relief valves and piping which all flows into a single crude relief tank. There are two or three relief valves each on the suction and discharge sides of each pump station (except Pump Station 4, with only suction relief, and Pump Station 1, with only discharge relief) and at the suction side of the VMT.

Relief valves are a critical component of pipeline integrity; they quickly dissipate excess pressures in the pipeline to avoid exceeding the maximum allowable operating pressure. The valves open very quickly — within 2 seconds — when certain operating parameters are exceeded. They stay open until pipeline pressure returns to acceptable levels.

The VMT relief system consists of relief valves which open and discharge crude oil to VMT storage tanks when pipeline pressure exceeds preset limits. These valves work in the same fashion as pipeline relief valves to prevent exceedance of the maximum allowable operating pressure upstream of the VMT.

A4.7 Pipeline Controls

The Operations Control Center (OCC) located in Valdez is key to pipeline operation and control. Pipeline controllers at the OCC monitor and control the pipeline to ensure safe, reliable operation. Effective control systems have allowed Alyeska to achieve a 99.6 percent reliability rating. (This means that TAPS is able to receive North Slope crude oil 99.6 percent of the time.) Central to OCC is the supervisory control and data acquisition (SCADA) host computer and associated equipment. The host computer interfaces between the OCC controllers (people) and computers at remote locations such as pump stations and remote gate valves. Some of the more significant controls systems are highlighted below.

A4.7.1 Supervisory Control and Data Acquisition System

SCADA controls oil movement and hydraulics, reports on variables such as temperature and pressure, and sounds alarms. It does so by transmitting conditions and alarms from the pump stations, field instruments, and control systems to the OCC controller personnel. SCADA also allows OCC computers to transmit process-control commands to local control systems at the pump stations.

A4.7.2 Remotely Operated Gate Valve System

Sixty-two RGVs (and one ball valve) help protect against oil spills. RGV controls are initiated either at the nearest upstream pump station or at the OCC. Each RGV is continually scanned for its opened or closed status. The pipeline control system's ability to communicate with the RGVs is critical. If communication between an RGV and the OCC is lost for longer than 2 minutes, the pipeline is automatically shut down to prevent pipeline overpressure.

Alyeska Pipeline Service Company

Photo 11. *TAPS gate valve.*

Once valve communication is reestablished, the pipeline is restarted.

A4.7.3 Hybrid Logic — Pump Stations 4 through 6

This system augments the normal RGV control system to account for high pipeline pressures at Atigun Pass (between Pump Stations 4 and 5) during an emergency pipeline shutdown. (A normal shutdown does not require hybrid logic.) This system ensures that RGVs close in a controlled fashion so that the pipeline will not overpressure during an emergency. Hybrid logic will quickly and reliably initiate mitigating action.

The need for such a specialized system was recognized during TAPS design, and determining which pipeline segments would require this additional care involved a great deal of study. All emergency shutdown modes were considered in the original pipeline design and were accounted for in the hybrid logic.

A4.7.4 Leak Detection Systems

TAPS leak detection systems provide early notification of potential pipeline leaks and have three levels of sensitivity. The systems are periodically upgraded as new technology becomes available. Today, TAPS has one of the most accurate leak detection systems of any pipeline.

A4.7.5 Telecommunications

Two primary communications systems are used on TAPS: the microwave system and the Alyeska Radio Telephone System (ARTS). Any pump station can contact the OCC at the VMT and vice versa. Any Alyeska vehicle can call or be called by the OCC, pump stations, or other vehicles. This critical ability helps ensure the safety of all workers and enhances operational efficiency.

The microwave telecommunication system provides voice and data communication for all TAPS facilities between Pump Station 1 and the VMT. Other Alyeska sites in Fairbanks and Anchorage link in through commercial telecommunication providers. This system uses a series of microwave towers on mountaintops along the pipeline.

ARTS is a radio dispatch system that provides radio communications along the length of the pipeline for two miles on either side of the right-of-way and to essentially all other TAPS sites. Other sites include each remote gate valve, oil-spill-response-equipment sites, pump stations, remote drag-reducing-agent injection sites, and airports.

A4.8 Fire-Protection Systems

Fire-detection systems along the pipeline and at the VMT notify personnel of potential and actual fires. Various devices detect anomalies and alert people through numerous alarms.

Automatic fire-detection systems are installed throughout pump station facilities. The main fire-alarm system at each station provides coverage in all buildings that are linked by the station hallway system. Fire-suppression systems are automatically activated when a fire has been detected. Pump-station fire panels normally operate in automatic mode, which allows all action to occur expeditiously. Actions can also be initiated manually at the fire-control panel or at the local fire-alarm stations. Automatic actions will also occur when the amount of hydrocarbon gases in an area reaches threshold levels.

VMT fire protection is made up of separate, interrelated elements that quickly control or extinguish fires. The primary elements of the system are onshore and offshore firewater systems, a foam system for tanks, a separate foam system for the East and West Metering Buildings, a Halon extinguishing system, and other auxiliary systems involving fire trucks and other fire-fighting equipment.

The onshore firewater system supplies seawater from Port Valdez to hydrants near critical buildings, tanks, and equipment in the VMT. Water from the firewater system also supplies two fixed foam systems protecting tanks in the East and West Tank Farms and supplies a separate metering-building foam system.

The offshore firewater system consists of a separate fire-control system for each berth. A firewater pump supplies seawater to each berth where it is mixed with foam. A redundant water supply from the onshore system backs up the primary source.

A4.9 Earthquake Monitoring System

The earthquake monitoring system (EMS) processes seismic data to evaluate the severity of earthquake groundshaking along the pipeline route and to assess the potential for damage to the pipeline and supporting facilities. The system's most important objectives are to determine whether the pipeline should be shut down in response to an earthquake and to delineate inspection requirements for the affected portion of the route.

Based on pre-established criteria, the EMS will sound alarms, generate event reports, and describe recommended structural inspections and their locations. The EMS also maintains an historical database of event parameters for detailed analysis. An EMS has been part of the pipeline control system since pipeline startup in 1977. The EMS consists of 11 remote digital strong-motion accelerograph (DSMA) stations located at Pump Station 1, Pump Stations 4 through 12, and the VMT.

The DSMA stations use a network to share data among the various processes at each station and between stations. All stations sense and process ground-motion data and perform system-wide processing of data that are broadcast and shared with all other DSMAs. The central computer for the pipeline control system is also connected to the EMS network to retrieve information to create displays and alarms at the pipeline controller's console in the Valdez OCC.

If an earthquake is detected, the DSMA switches into event mode and records time histories for each of the three axes of measurement. Visual and audible alarms are activated locally, and event alarms are passed to the pipeline control system for display at the OCC. When the earthquake has ended, the DSMA switches to post-event mode and computes and stores event parameters that indicate earthquake severity (Nyman et al., 1999).

Immediately after an earthquake, the EMS network distributes data from each affected DSMA so that all sites have data on the earthquake. Each DSMA processes the data to determine the severity of ground-shaking along the pipeline route. The computer generates graphs and printed reports, which assist the pipeline controller in decision-making and guide post-earthquake inspection efforts. A key report section compares computed earthquake parameters to design limits. If the shaken area requires an inspection, a checklist is generated to guide field-response teams.

The pipeline controller determines the need for pipeline shutdown and field inspection by reviewing EMS-generated alarm displays and other control system information. Shutdowns are initiated manually by the pipeline controller, but a shutdown sequence will occur automatically if seismic alarms are not acknowledged at the OCC within a preset period.

A4.10 Valdez Marine Terminal

The VMT (Figure 11) is the southern terminus of TAPS and is located on the southern shore of Port Valdez at the northeastern end of Prince William Sound. The site occupies approximately 1,000 acres extending from near sea level to 538 feet in elevation at the West Tank Farm.

Approximately 350 people work at the VMT, the primary functions of which include receiving, metering, storing, and transferring crude oil to ocean-going tankers for transport to market. The VMT also contains the OCC, Ballast Water Treatment Facility, and vapor control systems.

All oil flow at the VMT occurs through gravity — there are no pumps. Oil-handling facilities include:

- Eighteen storage tanks totaling 9.18 million barrels in capacity.
- Tanker loading facilities for up to 110,000 barrels per hour per berth.
- Four berths for loading of tankers, two with vapor controls.
- Meters to measure the oil that comes into the VMT and that goes onto tankers.

This report does not discuss the VMT in detail; however, the ballast water treatment system and vapor control system are discussed further in recognition of regulatory scrutiny of these facilities.

A4.10.1 Ballast Water Treatment Facility

The Ballast Water Treatment Facility (BWTF) processes ballast water offloaded from incoming tank ships and wastewater from a variety of waste streams collected in the VMT industrial wastewater sewer system.

Tank ships use seawater for ballast to maintain stability on their return journeys to Valdez after delivering crude oil to various ports. Some ships carry the ballast water in chambers segregated from the crude oil. This ballast water is discharged directly to Port Valdez after inspection for oil sheen in accordance with the National Pollution Discharge Elimination System permit for the VMT. Other ships carry ballast water in the same tanks used for storing crude oil on the outbound journey, and this ballast water contains residual hydrocarbons that cannot be discharged directly to Port Valdez. The contaminated ballast water is offloaded at the VMT, treated to remove remnant hydrocarbons and other contaminants, and then discharged to the marine waters of Port Valdez.

Multiple processes treat the ballast water. Some are designed to remove solids which do not dissolve in the water, while other, more rigorous processes must be used to remove oil which does not separate from the water. Improvements in technology have dramatically increased the ability to remove hydrocarbons. Compared with plant startup in 1977, the amount of hydrocarbon solids discharged was reduced tenfold by 1991. Those discharges have since been reduced another tenfold.

Monitoring is combined with dilution and mixing calculations to ensure that water quality standards are maintained within a permit-designated "mixing zone" in the port. The mixing zone is where effluent mixes with seawater. Outside the mixing zone, this dilution produces levels

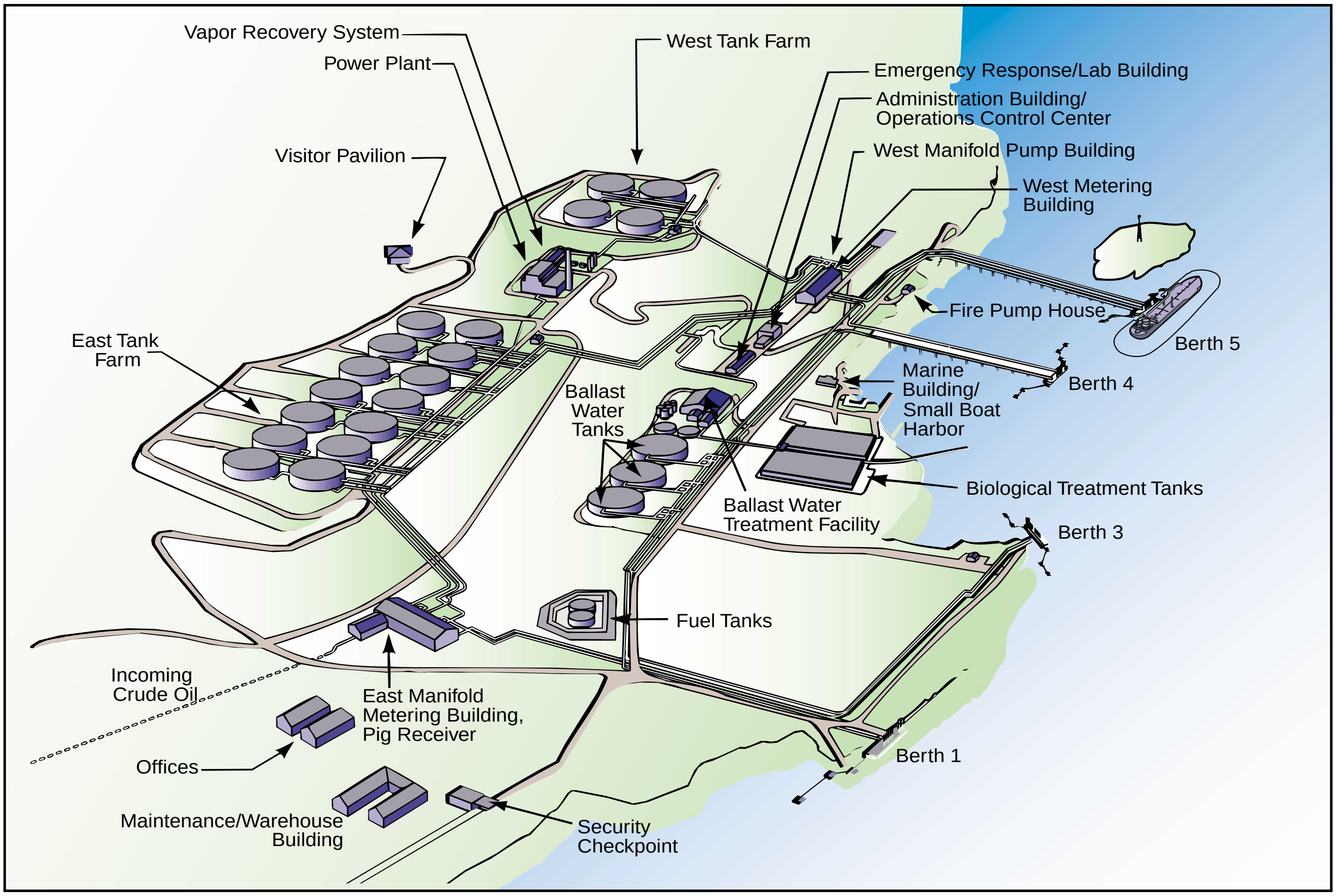

Figure 11. *Valdez Marine Terminal.*

of zinc, benzene, toluene, ethylbenzene, and xylene each well below the maximum concentrations allowed in State of Alaska Water Quality Standards.

A4.10.2 Vapor Control System

The vapor control system for the VMT controls air pollution by preventing atmospheric emissions of crude oil vapors from the storage tanks and from the tankers during loading. The vapor control system also provides inert (oxygen-deficient) vapor to the crude-oil storage tanks, thus maintaining a safe operating condition by preventing the vapor in the storage tanks from becoming combustible. Because a fire cannot sustain itself without oxygen, limiting the amount of oxygen in the tanks is a very effective fire-prevention measure.

The vapor control system is composed of an array of equipment and piping which collect crude oil vapor from the crude oil storage tanks and from the marine tank vessels. The vapor is continuously distributed among the storage tanks to fill the vapor space of tanks being emptied, routed to the powerhouse boilers to generate electricity, and sent to the incinerators for destruction.

The vapor control system serving the tank farms was part of the original construction of the VMT in the 1970s. A system was installed in 1997 to collect vapor from marine tank vessels during crude-oil loading operations.

Alyeska Pipeline Service Company

Photo 12. *View of the powerhouse and vapor recovery complex at VMT. The three stacks at left are vapor incinerators.*

Appendix 5
TAPS Integrity Assurance

Four primary mechanisms ensure the integrity of TAPS:
- A maintenance program ensures that equipment keeps working.
- Assurance systems ensure that proper procedures are followed and that quality standards are achieved.
- An open work environment encourages employees and contractors at all levels to report potential problems.
- Regulatory oversight further strengthens TAPS integrity by confirming that things are done correctly and by providing a public forum.

A5.1 Maintenance Program

The TAPS maintenance program is designed to preserve the integrity of TAPS facilities, systems, and equipment. Program activities include determining appropriate maintenance strategies; identifying and documenting maintenance work; performing preventive, predictive, and corrective maintenance; recording maintenance trends and history; and documenting completed work. The program also features an integrated maintenance-work history. The TAPS maintenance program thus provides assurance of the continued integrity of all TAPS assets.

Consistency in maintenance is achieved through use of the same processes, regardless of company, organization, or position. These processes are defined and documented in manuals and procedures, including:
- *Maintenance System Manual* (APSC, 1999d)
- *Quality Program Manual* (APSC, 1999e)
- *Corporate Safety Manual* (APSC, 2000b)
- *Document Management Interdepartmental Procedures* (APSC, 2000c)
- *Engineering Design Manual* (APSC, 1999f)
- Maintenance Procedures
- Safe Maintenance Procedures
- Operating Procedures

These manuals define standardized maintenance processes and provide for clear, concise, and consistent work performance, while allowing for flexibility where appropriate based on criticality. Processes and procedures are periodically reviewed to ensure uniformity, and continuous improvement, and to accommodate changes in the maintenance needs of TAPS.

The TAPS maintenance program is composed of ten elements:
- **Element 1, Maintenance Engineering.** Maintenance Engineering supports the maintenance of equipment and facilities by ensuring operational reliability, ensuring that regulatory requirements are met, and identifying optimization opportunities.
- **Element 2, Maintenance Strategy.** Reliability-based maintenance employs decision-tree methodology to ensure that appropriate regulatory requirements and best practices are incorporated into maintenance evaluation and decision-making processes.
- **Element 3, Financial Management.** Budgeting and financial management staff track maintenance costs and develop maintenance budgets to meet TAPS' near-term and long-term safety, quality, environmental, compliance, and financial goals.
- **Element 4, Planning and Scheduling.** This element organizes and prepares all work activities for maximum efficiency. People, equipment, tools, and other resources are placed where they are needed when they are needed.
- **Element 5, Work-Order Process.** Work-orders define and document the activities of operations and maintenance personnel for maximum effectiveness. This process also preserves historical information essential for continued operational reliability.
- **Element 6, Materials and Inventory.** Material handling, inventory management, vendor information, and the billing processes manage materials and inventory in support of operations and maintenance.
- **Element 7, Training.** The TAPS training program is broadly designed to provide familiarity with all aspects of the maintenance effort. Personnel training records are kept to document applicable training requirements and course completion.

- **Element 8, Maintenance Records and Change Management.** Equipment tags, maintenance records, and modifications to these records are maintained, and changes are noted on all documents and to interested personnel.
- **Element 9, Commitment Tracking.** This element tracks actions that are the result of a commitment to, or a request for, change, including maintenance analyses, evaluations, assessments, surveillance results, and audit findings.
- **Element 10, Performance Measurement.** Performance criteria, based on best practices, measure maintenance activities and performance companywide and are used to focus on specific areas of concern or opportunities for improvement.

A5.2 Assurance Systems

To ensure that key TAPS components remain operational and efficient, policies and procedures have been implemented to monitor equipment integrity. Administrative programs ensure that work is completed properly. Physical monitoring programs inspect components of the system to ascertain its continued integrity.

The **Alyeska Integrity Management System (AIMS)** is intended to document and communicate management expectations for the good business practices that should be reflected in Alyeska systems and processes. AIMS is a comprehensive, structured approach to integrity management designed to ensure safe, reliable operations. The goal of AIMS is to continually improve management systems that aid in preventing operational incidents, fires, spills, or leaks that harm people and the environment. AIMS provides a framework for documenting and communicating management expectations, for applying a consistent method of assessing progress to meet those expectations, and for achieving continuous improvement.

The Alyeska **Quality Program** describes policies and procedures created to ensure equipment integrity and provide management controls to maintain TAPS integrity. It assures management, the public, and regulatory agencies that TAPS operates reliably and satisfies requirements intended to protect the health and safety of the public and TAPS workers and to protect the Alaskan environment. The Quality Program applies to all work on TAPS, including design, construction, operation, maintenance, and ultimately, termination of TAPS.

A5.3 Open Work Environment

Alyeska continually strives to encourage an open work environment in which all employees and contractors are comfortable raising concerns of any nature with their supervisor, manager, or another authority within the company. This promotes a safe, efficient work environment.

Alyeska has developed a formal Code of Conduct outlining behavioral expectations for Alyeska employees and contractors. The Code of Conduct and the attributes of an open work environment give employees guidance for the appropriate action to take if they see that something is not right. This ability helps keep Alyeska's safety, efficiency, and integrity at the highest levels.

A5.4 Regulatory Oversight

In addition to internal assurance systems, TAPS has been the focus of oversight, regulation, legislation, and citizen involvement since construction was first proposed in 1969. Continuous monitoring of TAPS and Alyeska is provided by the JPO, which integrates the following agencies:

Federal Agencies

- Bureau of Land Management
- Department of Transportation/Office of Pipeline Safety
- Environmental Protection Agency
- Coast Guard
- Army Corps of Engineers

State Agencies

- Department of Natural Resources
- Department of Environmental Conservation
- Department of Fish and Game
- Department of Labor
- Division of Governmental Coordination
- Department of Transportation/Public Facilities

The Bureau of Land Management and the Alaska Department of Natural Resources jointly manage the JPO, which is charged with overseeing pipeline operations to ensure compliance with right-of-way agreements and applicable laws and regulations and to ensure safe operations, pipeline integrity, and environmental protection. The integration of staff from the various JPO agencies into teams based on monitoring requirements and issues promotes a coordinated approach.

Appendix 6
Related Operations

This section explores some related aspects outside the TAPS right-of-way, but in Prince William Sound. Although the focus of renewal of the Federal Grant and State Lease is on pipeline use of federal and state property, the pipeline system actually extends from Pump Station 1 to the Valdez tanker-loading facilities, and further includes tanker ship escort and spill response in Prince William Sound to Hinchinbrook Entrance, which is the entry point to the sound.

A6.1 Tankers

The size and composition of the tanker fleet serving TAPS will be changing over the next several years. Section 4115 of the Oil Pollution Act of 1990 (OPA 90; 33 CFR 157.10d) imposes certain requirements on tankers calling at U.S. ports and specifies which vessels are permitted to use U.S. ports by year, size of vessel (gross tons), hull design (single hulls, double bottoms, or double sides), and age of vessel. By the year 2015, all tankers calling on U.S. ports must have double hulls (double bottoms and sides). OPA 90 contains a schedule with eligibility requirements.

The current fleet serving the VMT consists of 26 tankers (NRC, 1991) — three with double hulls and 13 with double sides. However, the composition of the fleet must change in the future to stay in compliance with OPA 90. Figure 12 shows the planned phase-out schedule for existing Prince William Sound tankers based on U.S. Maritime Administration estimates published in a recent U.S. General Accounting Office study (GAO, 1999). According to this schedule, the last of the present tankers will be phased out by the end of the year 2013, and the fleet will consist exclusively of double-hulled tankers beginning in 2014. Double-hulled tankers offer environmental advantages in terms of a reduced likelihood and volume of oil spills (NRC, 1991; NRC, 1998).

There are substantial economies of scale in the construction and operation of tankers (GAO, 1999; NRC,

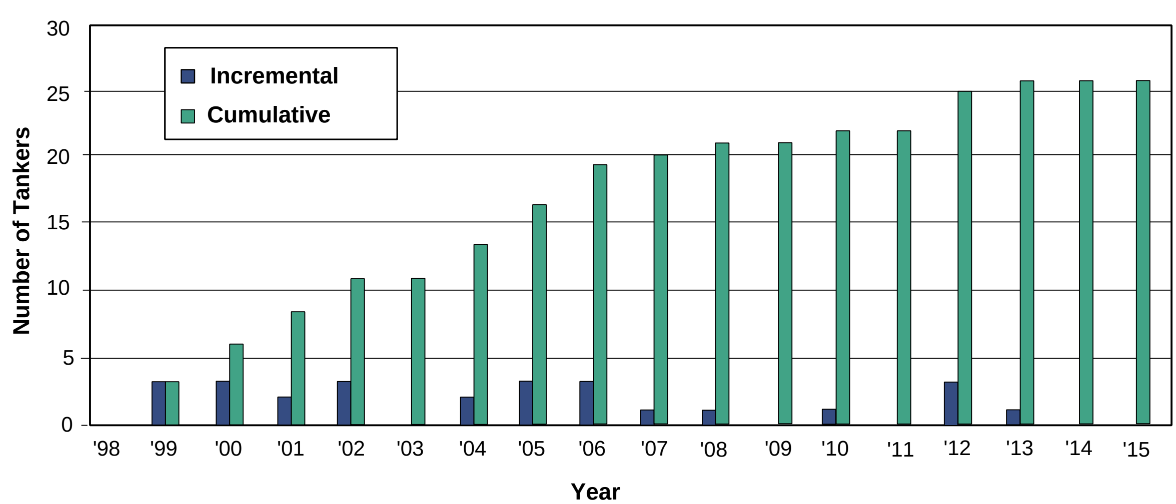

Figure 12. *Planned phase-out for existing TAPS-related tankers (GAO, 1999).*

1998), whether constructed in the U.S. or abroad. This consideration alone argues for construction of relatively large tankers. However, determining the optimal size for tankers serving the VMT is more complex, because draft constraints at many ports limit the utility of large tankers.

The costs of new double-hulled tankers are likely to be comparable to those for the Phillips Millennium Class tankers currently under construction at $166 million each. Thus, the total cost of the 8 to 10 new tankers will be from $1.3 billion to $1.7 billion — a substantial investment in the future of TAPS.

The number of tankers will decrease substantially from the present 26 tankers to 8 to 10 tankers by 2020 (Figure 13). Fewer tanker transits and the use of double-hulled tankers and other improvements will substantially reduce the annual probabilities of accidents and oil spills.

A6.2 Ship Escort/Response Vessel System

Prevention and cleanup of oil spills have always figured in the design and operation of TAPS; however, in the aftermath of the *Exxon Valdez* oil spill in 1989, Alyeska, the TAPS Owners, regulators, and Congress conducted a comprehensive examination of ways to improve oil spill performance. Among other things, this resulted in the passage of OPA 90, which includes requirements for spill prevention and response.

Significant improvements have been made in spill prevention and response capability for Prince William Sound, including the creation of Alyeska's Ship Escort/Response Vessel System (SERVS). SERVS is responsible for the safe transit of oil tankers from the VMT to international waters. Its duties are primarily related to spill prevention and spill response. A study by Det Norske Veritas et al. (1996), which did not consider future benefits of double-hulled tankers, estimated that the risks of a large oil spill were reduced by 75 percent as a result of the creation of SERVS and related measures.

SERVS has nine vessels assigned to escorting, docking, and response duties, and at least two escort vessels are required for each laden tanker transiting the sound. Tethered escort is required through Valdez Narrows. In the northern sound, the escort vessels will be within one-quarter nautical mile of the tanker when not tethered. In the central sound, a conventional tug or a prevention and response tug (PRT) will maintain close escort, while the second escort vessel goes on sentinel duty to provide response coverage to a larger area. A vessel is on sentinel duty in the Hinchinbrook Entrance area. A third escort vessel may be added, depending on weather conditions. Additional vessels are available if needed for a response or to fill in during scheduled and unscheduled maintenance.

- Currently, the three PRTs and two enhanced tractor tugs (ETTs) are designated to fill escort and response duties. These vessels carry response equipment such

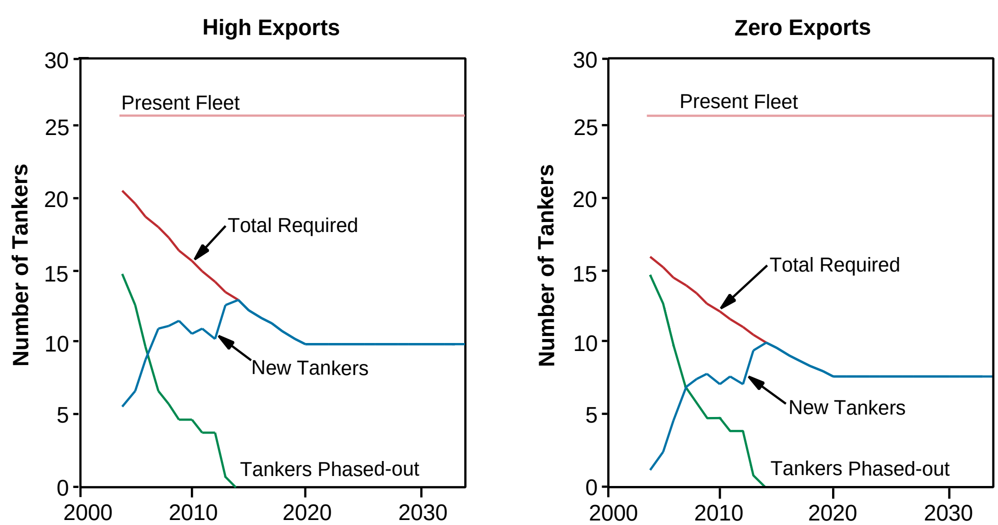

Figure 13. *Tanker projections (ECA, 1999).*


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Photo 13. *The* Alert, *a new prevention and response tug added to the Alyeska SERVS fleet in 2000.*


Alyeska Pipeline Service Company

Photo 14. *A SERVS vessel escorts a tanker in Prince William Sound.*

as boom and skimmers. The escort vessels accompanying each laden tanker monitor the vessel's actions and will radio the escorted tanker to question or alert the tanker of atypical behavior. The tanker notifies the escort vessels upon recognition of a loss of steering and/or propulsion or suspected equipment malfunction.

- All laden tankers must have one tethered escort in the northern sound from Port Valdez to Bligh Reef light.
- One vessel is stationed in the Hinchinbrook area (including Port Etches) to provide sentinel assistance to tankers in Hinchinbrook Entrance. This vessel, which is also used as a close escort vessel for laden tankers, has open-ocean rescue capabilities.
- The two ETTs were built specifically for service in the sound and were both deployed in 1999.
- The three 140-foot, 10,000-horsepower PRTs were deployed in 2000. They have twice the horsepower and are more maneuverable than the escort/response vessels they replaced.

In addition, Alyeska manages the largest spill response equipment stockpile in the world, including more than 70 oil-skimming systems, 7 storage barges, and 35 miles of containment boom. Equipment is stationed in Port Valdez and at five Response Centers across Prince William Sound. In addition, Alyeska has contracts with over 300 fishing-vessel owners to respond to a potential spill. Fishermen also provide local knowledge to help identify at-risk areas and provide protection methods.

Other improvements made in the wake of the *Exxon Valdez* oil spill include:

- Regular oil spill drills and training exercises are conducted at a variety of locations along the pipeline and in Prince William Sound.
- The Prince William Sound Regional Citizens' Advisory Council was formed in accordance with OPA 90. This citizens' group participated in the design of Alyeska's new system based on prevention and readiness for response.

Alyeska spends $60 million annually on an organization with over 200 people engaged in spill prevention and response activities in Prince William Sound.

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Acronyms

ADEC	Alaska Department of Environmental Conservation
AIMS	Alyeska Integrity Management System
API	American Petroleum Institute
ARTS	Alyeska Radio-Telephone System
bbl	Barrel(s)
BLM	Bureau of Land Management
BWTF	Ballast Water Treatment Facility
CCMP	Corrosion Control Management Plan
CKV	Check valve
DRA	Drag-reducing agent
DSMA	Digital strong-motion accelerograph
EIS	Environmental impact statement
EMS	Earthquake monitoring system
ETT	Enhanced tractor tug
JPO	Joint Pipeline Office
MGV	Manual gate valve
MLA	Mineral Leasing Act of 1920
OCC	Operations Control Center
OPA 90	Oil Pollution Act of 1990
PRT	Prevention and response tug
psi	Pounds per square inch
RGV	Remote gate valve
SCADA	Supervisory Control and Data Acquisition
SERVS	Ship Escort/Response Vessel System
TAPAA	Trans-Alaska Pipeline Authorization Act
TAPS	Trans Alaska Pipeline System
VMT	Valdez Marine Terminal
VSM	Vertical support member